SPE 12316

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Society of Petroleum Engineers of AIME

Production Potential From Devonian Gas Shales: Effective Production Strategies

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ABSTRACT

The estimate of technically recoverable gas from Devonian shale in Ohio ranges from 6.2 to 22.5 Tcf, depending on stimulation method and pattern size selected. This estimate is based on (1) a compilation of the latest geologic and reservoir data, (2) analysis of key productive mechanisms, and (3) examination of alternative stimulation and production strategies.

The key findings of this study are:

- A substantial volume of gas is recoverable, although advanced technology will be required to reach economically attractive production rates in the state,
- Well spacing can be reduced by half from the traditional 150 to 160 acres per well without severly impairing per-well recovery, and
- Due to the high degree of permeability anisotropy in the shales, a rectangular, generally 3 by 1 well pattern leads to optimum recovery.

INTRODUCTION

Devonian shales constitute one of the largest worldwide concentrations of organic carbon. Recent estimates of the total gas in-place range from 844 Tcf to 2,579 Tcf, as determined by the U.S. Geological Survey and Mound Facility, respectively. However, technological challenges of efficiently recovering and economically producing the hydrocarbons locked in the Devonian shales are formidable and have yet to be solved.

To date, full development of this resource has been impeded by a lack of scientific description and analysis of the gas production mechanisms in the organic shales. The geologic setting of the Devonian shales is highly complex in that the shales are a combination of source bed, reservoir, and seal in multiple stratigraphic horizons. Conventional geologic and engineering measures need to be supplemented by improved reservoir models that describe the natural fracture system, permeability anisotropy, and the release of adsorbed gas.

Tables and figures at end of paper.

In addition, effective development has been constrained by uncertainties in the use of extraction and well stimulation technologies and limited understanding of how stimulation technologies perform in the naturally fractured, anisotropic shale rocks.

Recently, a number of major studies and activities have been completed under the Eastern Gas Shales Project (EGSP) that provide a basis for advancing an understanding of the Devonian gas shales. Under the sponsorship of the U.S. Department of Energy's Morgantown Energy Technology Center (DOE/METC), two geological and geochemical assessments of the Devonian shales have been completed by the Mound Facility and Cliffs Minerals, namely:

- "Resource and Exploration Assessment of the Oil and Gas Potential in the Devonian Gas Shales of the Appalachian Basin," Mound Facility, 1982.[1]
- "Basin Analysis of the Devonian Shales in the Appalachian Basin," Cliffs Minerals, June 1982.[2]

Their detailed reports provide much information as to the fracture system, stratigraphic sequence and gas content of the shale. In addition, DOE/METC has developed a reservoir simulator called SUGAR (Simulator for Unconventional GAs Resources) that is capable of handling many of the unique features of the shale not commonly found in other simulators, such as dual porosity, fracture flow, and permeability anisotropy.[3]

Paralleling the analytic work has been a series of field research projects, such as the Offset Well Test Program (OWTP)[4,5] in Meigs

County, Ohio to identify the net productive interval and permeability anisotropy; the drilling of a deviated well to measure natural fracture spacing; and, the drilling of a series of Eastern Gas Shales Project core wells to establish basic data on shale porosity, permeability, and organic carbon content.

Finally, there has been a recent upsurge in drilling, testing, and well stimulation by industry that is yielding new data on previously undrilled areas of the Appalachian Basin.

PURPOSE

The current study integrated the previous research work with additional data in addressing the following five study objectives:

1) A rigorous investigation, model development, and description of the gas production mechanisms in the Devonian gas shales. This study examines the gas storage and production mechanisms in the naturally fractured, dual porosity systems that govern productivity in Devonian shales beyond the conventional mechanisms of drainage area, net pay, porosity, permeability, and pressure.

2) The collection and assembly of essential geologic and reservoir data. While much of the data required for this analysis is assembled from previous research, it is augmented by the collection of new data on well completion and gas production.

3) The partitioning of the state into study regions. For the purposes of analysis, the state of Ohio is partitioned into regions based on geologic data and gas production trends.

4) An investigation of the efficiency of alternative well stimulation and production strategies. The relative efficiencies of borehole shooting, radial stimulation, and vertical fracturing are analyzed using a numerical reservoir simulator specifically designed for the key production features of the Devonian shales.

5) An estimate of the production potential in Ohio. Technically recoverable reserve estimates are made for each of the major partitioned areas of Ohio, for various stimulation techniques. The target interval of this analysis will be the Middle and Lower Huron shale members of the Upper Devonian Ohio Shale, since these units are the dominant productive units in Ohio.

GENERATION OF INPUT DATA

The input data required to conduct this analysis required a large cross section of information. The process consisted of seven major steps, as discussed below:

1) Identification of Constant Geologic/Reservoir Data. Several reservoir parameters, such as matrix permeability and porosity, were found not to vary widely and thus were kept constant over the study area. These reservoir data and parameters were assembled from:

- Historical gas production and well records,
- The EGSP core well program, and
- The Offset Well Test Program (Meigs County, Ohio)

The reservoir parameters required for the analysis are shown on Table 1.

2) Development of Variable Geologic Data By County. Reservoir parameters that showed strong regional variation, such as gas content and pressure, were developed for each county from actual data or were extrapolated from a series of isoline maps developed for Ohio (Figures 1 and 2) using available well information. In addition, the natural fracture spacing identified for the state of Ohio is shown in Figure 3. The data was assembled using:

- Geological and geochemical reports by Cliffs Minerals and Mound Facility;
- Fracture conductivity studies by Terra Tek;[6]
- Stress-ratio maps prepared by METC/DOE;[7] and
- Rock pressure data from 257 wells in 15 counties.

3) Assembly of Actual Gas Production Data. Historical gas production data for Ohio were gathered from state and company records, as follows:

- Long-term production data were assembled from 108 wells in 11 counties; and
- Initial open flow (24 hr.) data were collected from 222 wells in 15 counties.

4) History Matching of Production Data and Productive Interval. The SUGAR reservoir simulator was used to match production data and back-calculate the remaining unknown reservoir parameters of fracture permeability and net productive interval, as well as to ensure consistency in the basic data. An overview description of the SUGAR model is found in the Appendix.

5) Definition of the Fracture Regimes. Beyond the data required for analyzing the performance of well stimulation by borehole shooting, additional geologic data were required to properly evaluate well performance with improved stimulation technology. This additional data included:

- Determining directional components of fracture permeability to reflect permeability anisotropy;

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- Identifying the expected angle of intersection between induced and natural fractures to estimate whether the induced fracture will cross or terminate in the natural fracture system;[8] and

- Establishing an optimum well drainage geometry to best match permeability anisotropy and stimulation method.

Natural and induced fracture orientation along with permeability anisotropy are shown on Figure 4.

6) Development of Six Regional Partitions for Ohio. Gas production estimates were made for each county using the geologic and production data developed in Steps 2 through 5, above. The state of Ohio was then partitioned into six areas (Figure 5) based on the key geologic data that establish the natural stress and native fracture orientations, mechanical fabric of the shale, and 40-year cumulative gas production. The distribution of production data is also shown by region on Figure 5.

7) Development of Representative Data by Partitioned Area. The essential geologic data were aggregated and compiled by each of the six partitioned areas and is summarized in Table 2.

ANALYSIS OF STIMULATION METHODS

Three well stimulation techniques (beyond traditional borehole shooting) were evaluated. Two basic types of stimulations have been examined; vertical fracturing and radial stimulation. The radial stimulation case assumed an increased permeability around the wellbore to a distance of 30 feet, while the vertical fractures were considered to have 150-foot and 600-foot frac wings, well propped to the tip of the fracture.

The three cases are summarized below:

- Radial Stimulation (r'_w = 30 feet): emerging technology that achieves omni-directional induced fractures in an uncased well.

- Small Vertical Fracture (x_f = 150 feet): achieved by hydraulic fracturing with small volumes of fluid (less than 40,000 gallons), and

- Large Vertical Fracture (x_f = 600 feet): potentially attainable with significant advances in technology using large volumes of fluid (greater than 150,000 gallons).

The data which had been assembled by area was analyzed for each of the delineated stimulation cases using the SUGAR Model.

PRODUCTION POTENTIAL

The Devonian shales of Ohio (Middle and Lower Huron member) offer an important future source of natural gas. The target intervals analyzed by this study contain an estimated 50 Tcf of gas in-place. Recent research shows that a major portion of this gas may be feasibly recovered, as discussed below:

- Gas recovery and flow rates per well vary widely, with highest recoveries in southern Ohio. Highest gas production rates and ultimate recovery can be expected in southern Ohio (Area I). Gas recoveries per well can reach 1,000 MMcf (40-year cumulative recovery with large, 600-foot half length, vertical fractures) with gas flow rates of 200 Mcf per day (daily average for first four years). Lowest recovery and gas flow rates are in northeast Ohio (Area VI). Here ultimate recovery is estimated at 24 MMcf (40-year cumulative recovery with 60-foot radial stimulation) with gas flow rates of 2 Mcf per day.

- Improved stimulation technology is required to unlock the full gas potential. Use of large vertical fractures in the high gas potential Area I will provide per well cumulative recoveries (over 40 years) of 1,080 MMcf versus 386 MMcf by borehole shooting. Even in the low gas potential Area VI, large radial stimulation would more than double the gas flow rates and ultimate recovery as compared with borehole shooting. Future technological advances for more efficiently interconnecting the natural fracture system to the well drainage area would further add to gas recovery.

- Alternative well spacing and pattern configuration will also help increase gas recovery. Reducing well spacing, to 80 acres per well, will substantially increase gas recovery--from 15.2 Tcf at 160 acres to 22.5 Tcf at 80 acres--without appreciably reducing recovery in the initial years. In addition, changing the well pattern alignment to a 3 by 1 rectangle from the traditional square pattern improves gas recovery per well by 5 to 10 percent.

- The production potential from the target sequence of Devonian shales of Ohio ranges from 6.2 to 22.5 Tcf. The low end of the range reflects well stimulation by borehole shooting and current field development practices. The high end of the range reflects application of advanced stimulation technology (vertical fracturing and radial stimulation) and use of alternative field development methods. Production by Area and stimulation technology is shown in Table 3.

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ANALYSIS OF ALTERNATIVE PRODUCTION STRATEGIES

Traditional development of the Devonian shale resource in Ohio used such practices as borehole shooting and uncased wells on 160-acre spacing. Currently, several new technologies and development practices are emerging that can lead to increased recovery and lower cost gas. This section examines three alternative production strategies: 1) advanced well stimulation technology, 2) reduced pattern size, and 3) alternative pattern shape, along with alternative induced fracture behavior at natural fracture intersections.

A. Advanced Well Stimulation Technology

Analysis shows that advanced stimulation methods add significant additional gas over borehole shooting. Previously, it had been assumed that merely linking the natural fracture system to the wellbore was sufficient to achieve efficient gas recovery, and that the greater the number of natural fractures connected, the greater the resulting gas recovery.

This analysis showed, however, that a higher conductivity path than provided by the natural fracture system is required to achieve efficient gas flow rates. This is because the permeability in the natural fracture system is too low (0.02 to 0.30 md) to provide adequate conductivity; thus, an induced fracture with proppants and high conductivity is required for efficient gas recovery.

The expected increase in gas productivity, due to the application of advanced well stimulation, must be weighed against the extra cost of the stimulation treatment. One method for so doing is to determine if the additional expense of the stimulation treatment could be paid back over a specified period of time.

In this study, Areas I an II were selected for direct comparison. The table below indicates the incremental gas production (MMcf) over borehole shooting in Areas I and II in 5 years:

Type of Stimulation	Incremental Gas Recovery, In 5 Years, Over Borehole Shooting (MMcf/Well)	
	Area I	Area II
Radial Stimulation	35.0	19.1
Small Vertical Fracture	100.0	32.7
Large Vertical Fracture	282.8	76.4

If a 5-year payoff period is adequate and a wellhead value of $3/Mcf is assumed for the additional gas produced, a large vertical fracture treatment would be cost effective in Area I if it cost less than $800,000. Similarly, in Area II, a small veritcal fracturing would be cost-effective if it could be accomplished for under $300,000. Cumulative production curves are shown for the two areas in Figures 6 and 7.

B. Reduced Pattern Size

The traditional field development practice is to use a well spacing of 150 to 160 acres, drilled on a square pattern. The analysis shows that, with this spacing, a considerable portion of the gas in-place remains unrecoverable even after 40 years. Today, current practice is to drill on a smaller acreage spacing. This analysis therefore examines the recovery efficiencies and feasibility of reducing pattern size to 80 acres per well.

While closer drilling will yield a higher overall gas recovery from a given area, the feasibility of drilling on smaller patterns has to be weighed against the expense of the additional well and stimulation. For example, the table below illustrates the effects on cumulative gas production, for the first five years, of drilling one and two wells on 160 acres in Area I:

Effect of In-Fill Drilling
(5-Year Cumulative Gas Recovery, MMcf)

	160 Acres		Incremental Gas for
	1 Well	2 Wells	2nd Well
Borehole Shooting	61	122	61
Large Vertical Fracture	344	670	326

The table above shows that drilling on 80-acre spacing would yield an additional 61 MMcf (over the first 5 years) using borehole shooting, and an additional 326 MMcf (in 5 years), using large vertical fracturing. In this area, drilling on an 80-acre spacing would be nearly as economical as drilling on 160-acres. Cumulative production for all stimulation techniques on an 80-acre spacing in Area I is displayed on Figure 8.

C. Alternative Pattern Shape

This study indicated that a rectangular drainage pattern is more efficient in recovering gas than a square pattern in anisotropic permeability regions. This analysis examines the cumulative gas recovery for three stimulation technologies (borehole shooting, a radial stimulation, and a large vertical fracture) over three drainage shapes (a square, a 3 by 1 rectangle, and a 5 by 1 rectangle). Area II which exhibits a permeability anisotropy ratio of 6:1 and a fracture intersection angle of 10 degrees was used in this analysis. Radial stimulation and vertical fracturing in a 3 by 1 rectanglar drilling pattern are illustrated in Figure 9.

The analysis shows that when borehole shooting is used for well stimulation, the drainage shape has little impact on gas recovery, Table 4. However, for the other two stimulation techniques, recovery efficiency is improved 5 to 10 percent by using alternatives to the traditional square pattern. The most efficient drainage shape appears to be a rectangle of about 3 by 1, although the optimum dimensions will depend upon the stimulation technique used, drainage pattern size, and the permeability anisotropy in the region. Further study is required to determine the optimal drainage pattern shape under the large variety of geologic variables and well stimulation practices present for the Devonian shale.

D. Alternative Induced Fracture Behavior at Natural Fracture Intersections

Previous stimulation theory held that the primary goal of stimulation was to link the well bore with the natural fracture system. This may not always be adequate however to produce gas economically. In many areas of Devonian shale, the permeability of the natural fractures may be such that it restricts the potential flow of gas. In these cases a large well-propped fracture will have a significant effect on improving gas flow. This is illustrated by the behavior of an induced fracture at a natural fracture interface. The basic analysis assumes that an induced fracture will enter and propagate along the same path as the natural fracture system. However, two other possibilities could occur:

- The induced fracture could enter the natural fracture system and terminate due to energy dissipation at the interface; or,
- The induced fracture could cross the natural fracture system for the full fracture design length.

These three alternatives are shown schematically on Figure 10 and are analyzed here as a sensitivity analysis.

1. Low Fracture Intersection Angle

In areas having a low induced fracture intersection angle (with the natural fracture system), it appears to make little difference whether the fracture parallels or crosses the natural fracture system. However, with a large-scale stimulation (a 600-foot induced fracture) substantial improvement in gas recovery results when the induced fracture parallels (providing a well-propped, highly conductive flow path) rather than terminates in the first natural fracture system encountered.

The results of this analysis for Area II, which has a fracture intersection angle of 10 degrees are indicated in Table 5.

For Area II, crossing the natural fracture system results in only a small (3 percent) increase in gas recovery for both the small and large vertical fracture cases. However, should the induced fracture merely terminate in the natural fracture system, gas recovery could be severely reduced--by 20 percent for the small, 150-foot vertical fracture case, and by 50 percent for the large, 600-foot vertical fracture case.

2. High Fracture Intersection Angle

At higher fracture intersection angles such as 40 degrees, the positive effects of crossing a natural fracture system become evident. In this type of setting, the induced fracture presents a high permeability surface area partially orthogonal to the direction of greater natural permeability.

The reservoir properties of Area IV, which has a 40 degree intersection angle and a permeability anisotropy ratio of 6:1, are used to examine the effect of fracture intersection angle (Table 6).

For Area IV, crossing the natural fracture system increases gas recovery by 40 to 50 percent over the case where the induced fracture merely parallels the natural fracture system.

SUMMARY

Four major findings emerge from this study:

1. A Considerable Amount of Geological/Geophysical Data is Required to Properly Simulate the Gas Production Mechanism of the Devonian Shales. Beyond the conventional gas storage and production mechanisms, the major controlling factors in the Devonian shale include fracture permeability and intensity, permeability anisotropy, adsorbed gas, the capacity to connect the natural fracture system to a wellbore, and the difficult-to-measure (by conventional means) net productive interval. While recent work has begun to provide some of this data, a considerable amount of extrapolation and reliance on assumption was required for this study. Substantial future research and drilling is still required to reduce the uncertainty and risk surrounding gas production from Devonian shales.

2. Improved Stimulation Technology is Required to Unlock the Full Gas Potential. Use of large vertical fractures, in the high gas potential Area I, will provide per well cumulative recoveries (over 40 years) of 1,080 MMcf versus 386 MMcf when borehole shooting is used. Even in the low gas potential Area VI, radial stimulation would more than double the gas flow rates and ultimate recovery, as compared with borehole shooting. Other advances, for more efficiently interconnecting the full natural fracture system to the wellbore, would further increase gas recovery.

3. Alternative Well Spacing and Pattern Configuration Will Help Increase Recovery. Reduced well spacing to 80 acres per well will also increase gas recovery (from 15.2 Tcf at 160 acres to 22.5 Tcf at 80 acres) without appreciably reducing gas recovery in the initial years. In addition, when using one of the improved stimulation methods, changing the pattern alignment to a 3 by 1 rectangle instead of a square will add from 5 to 10 percent recovery per well.

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4. The Devonian Shales of Ohio Offer a Major Source of Production Potential. Production potential from the Middle and Lower Huron interval in Ohio was estimated for each of the six partitioned areas. In total, recoverable gas ranges from 6.2 to 15.2 Tcf over 40 years (depending on stimulation) from wells drilled on 160-acre spacing in the Middle and Lower Huron members. Average production per well was found to be highest in southern Ohio (Area I) and to generally decline northeastward over the state.

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6. SPE Symposium on Low Permeability Reservoirs, Experimental Evaluation of Fracturing Fluid Interaction With Tight Reservoir Rocks and Propped Fractures (Terra Tek) 1979.

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SUGAR MODEL APPENDIX

The model used in this study is the two-dimensional numerical model (SUGAR-MD) available at DOE/METC. This model was developed specifically for analyzing Devonian Shale production and includes the three key sources for gas storage and production; namely:

- The macro-fracture system,
- The micro-fracture system, and
- Gas adsorbed on the organic kerogen in the shale.

The SUGAR model describes the transient pressure response of a naturally fractured reservoir by two dimensionless parameters: the dimensionless fracture storage coefficient, ω, and the dimensionless fracture transfer coefficient, λ. These are defined as follows:

- The dimensionless fracture storage coefficient, ω, is defined as:

$$\omega = \frac{\Phi_f}{\Phi_f + \Phi_m}$$

where: Φ_f = fracture porosity
Φ_m = matrix porosity

The dimensionless fracture transfer coefficient, λ, is defined as:

$$\lambda = \frac{8}{a^2} \quad \frac{k_m}{k_f/r_w{}^2}$$

where: $2a$ = fracture spacing
k_f = fracture permeability
k_m = matrix permeability
r_w = well bore radius

The two dimensionless parameters used by the SUGAR simulator establish a direct relationship between certain of the reservoir parameters. The dimensionless transfer coefficient, λ, determines the interdependence between k_m, k_f, and r_w. This means that unless two of these parameters are known with certainty, the third cannot be determined as an independent value from history matching. In addition, any uncertainty in the magnitude of one of the parameters will have a direct effect on the value of one or both of the other parameters.

In addition, there are two unconventional gas storage parameters:

- h = "net productive" interval
- G_c = adsorbed gas content

The proper selection of values for these parameters can lead to a highly accurate history matching of actual gas production.

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TABLE 1
REQUIRED RESERVOIR PARAMETERS

A. Constants	Representative Value or Range	Source
Drainage Area, A	160 Acres	Historical Production
Matrix Permeability, k_m	5×10^{-6} md	Core Analysis & Simulation
Matrix Porosity, Φ_m	0.01	Offset Well Test; Core Analysis
Fracture Porosity, Φ_f	0.0009	Offset Well Test
B. Variables, By Area		
Fracture Permeability, k_f	0.02 - 4 md	Laboratory Tests (Terra Tek); Stress Ratio (DOE/METC)
Gas Content, G_c	10 - 220 Mcf/AF	Mound Report
Initial Pressure, P_i	65 - 815 psia	Well Records
Line Pressure, P_l	25 - 100 psia	Estimated
Fracture Spacing, a	10 - 30 feet	Cliffs Minerals Report; Stress-Ratio Map
C. Matching Parameters		
"Productive Interval," h	10 - 120 feet	Simulation

TABLE 2
AVERAGE RESERVOI[illegible]PERTIES BY AREA

Partitioned Area	Depth (feet)	Net Thickness (feet)	Gas Content (Mcf/AF)	Fracture Spacing (feet)	Fracture Perm. (md)	Permeability Anisotropy (ratio)	Intersection Angle (degrees)	Rock Pressure (psia)
I	2,320	119	100	10	0.0276	1:1	N/A	690
II	1,500	60	90	20	0.2993	6:1	10	240
III	3,560	120	20	20	0.0200	4:1	20	525
IV	1,660	105	140	20	0.0574	6:1	40	215
V	365	10	200	20	4.4290	8:1	40	90
VI	2,135	100	50	20	0.0200	8:1	40	135

TABLE 3
PRODUCTION POTENTIAL, BY AREA
AND STIMULATION METHOD

Partitioned Area	Total Drillable Area (Sq. Mi.)	Gas In-Place (Tcf)	Production Potential (Tcf) in 40 Years: Borehole Shooting	Radial Stim. $r'_w=30'$	Small Vertical Fracture $x_f=150'$	Large Vertical Fracture $x_f=600'$
I	543	4.1	0.84	1.16	1.58	2.35
II	3,577	12.4	2.95	4.06	4.67	6.21
III	2,869	4.4	1.46	1.98	2.33	3.04
IV	2,641	24.8	0.84	1.35	1.78	3.38
V	313	0.4	0.05	0.06	0.06	NA
VI	1,035	3.3	0.04	0.07	0.09	0.20
TOTAL	10,978	49.4	6.18	8.68	10.61	15.18

TABLE 4

SELECTION OF DRAINAGE PATTERN SHAPE

AREA II

Stimulation Technique	Cumulative Gas Recovery From Alternative Patterns Square Pattern (MMcf)	3X1 Pattern (MMcf)	6X1 Pattern (MMcf)
Borehole Shooting			
10 Years	63	63	63
40 Years	206	206	206
Radial Stimulation			
10 Years	94	99	95
40 Years	261	274	263
Large Vertical Fracture			
10 Years	172	190	180
40 Years	402	434	414

TABLE 5

EFFECT OF ALTERNATIVE INDUCED FRACTURE PERFORMANCE

LOW ANGLE CASE

	(Cumulative Recovery, MMcf)		
Stimulation Technique	Terminates In Natural Frac System	Parallels Natural Frac System	Crosses Natural Frac System
Small Vertical Fracture			
10 Years	97	121	127
40 Years	281	327	337
Large Vertical Fracture			
10 Years	97	190	198
40 Years	281	434	444

TABLE 6

EFFECT OF INDUCED ALTERNATIVE FRACTURE PERFORMANCE

HIGH ANGLE CASE

	(Cumulative Recovery, MMcf)	
Stimulation Technique	Parallels Natural Frac System	Crosses Natural Frac System
Small Vertical Fracture (x_f=150')		
10 Years	49	74
40 Years	168	243
Large Vertical Fracture (x_f=600')		
10 Years	103	159
40 Years	320	461

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Figure 1
LOWER AND MIDDLE HURON UNITS
Gas Content (Mcf/AC-Ft.)

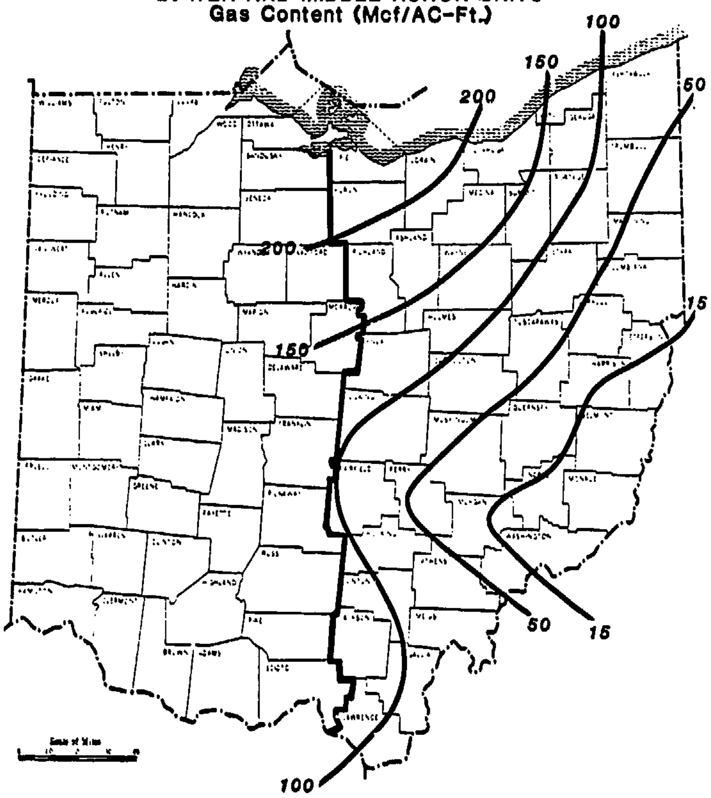


Figure 2
ROCK PRESSURE (psig)

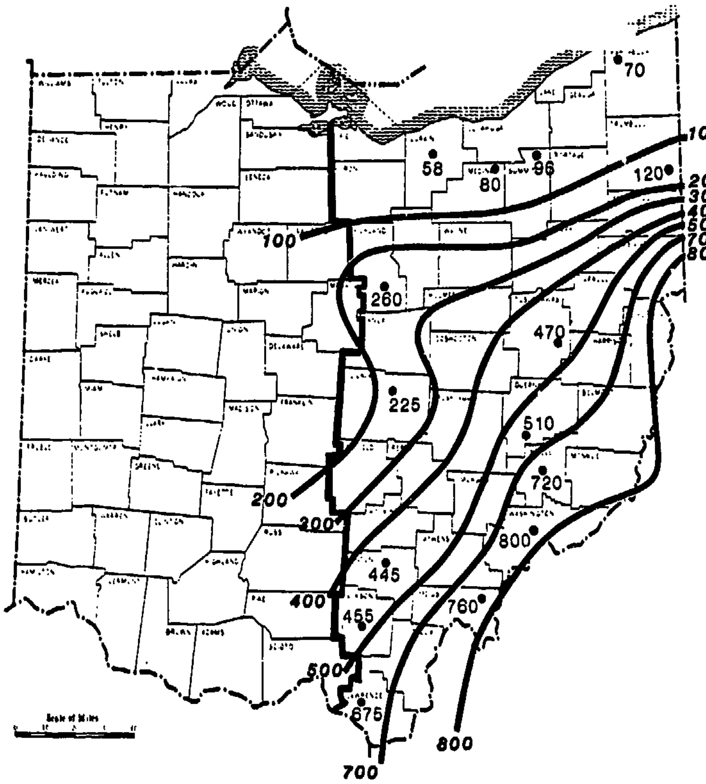


Figure 3
NATURAL FRACTURE SPACING
(feet)

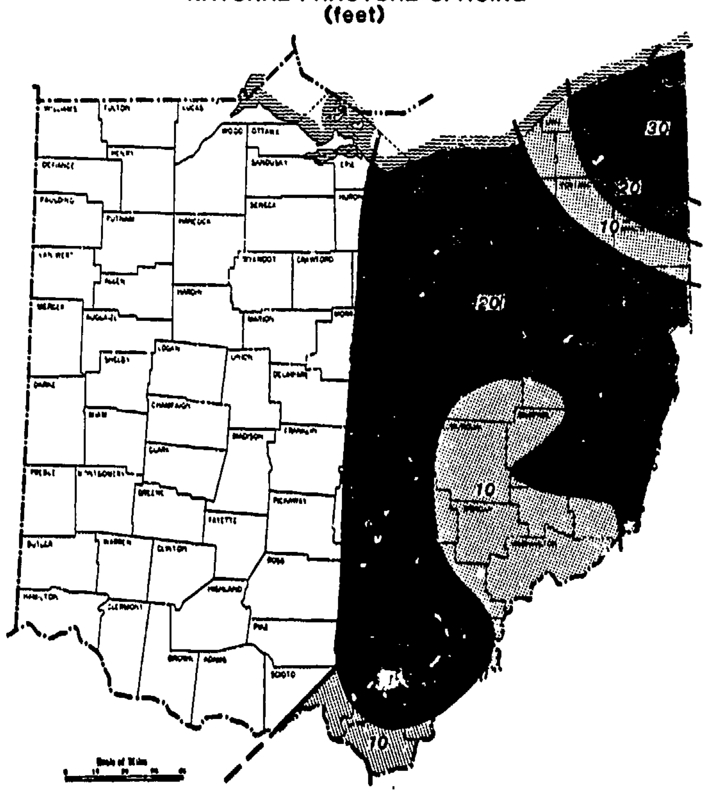


Figure 4
REGIONAL ORIENTATIONS
NATURAL vs. INDUCED FRACTURES

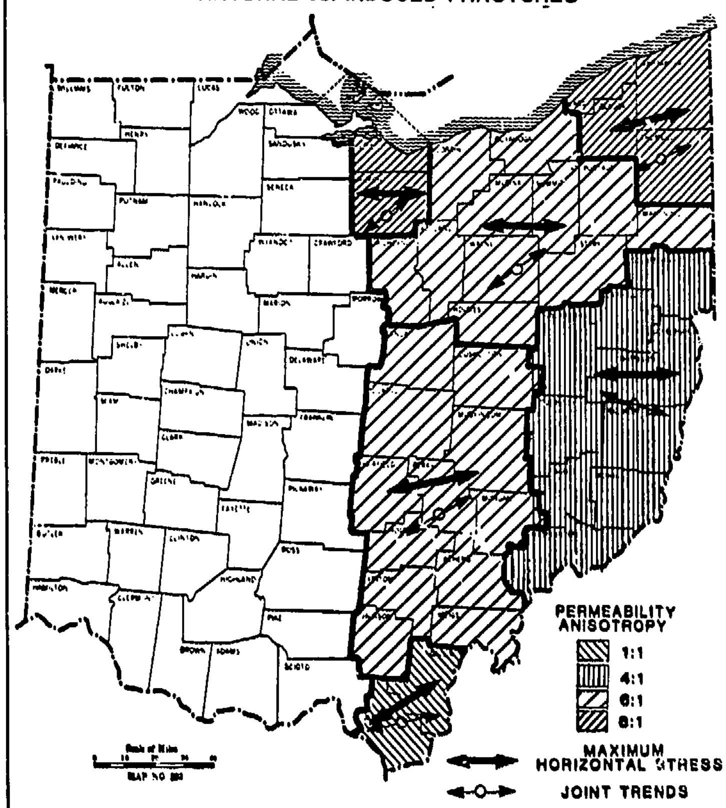
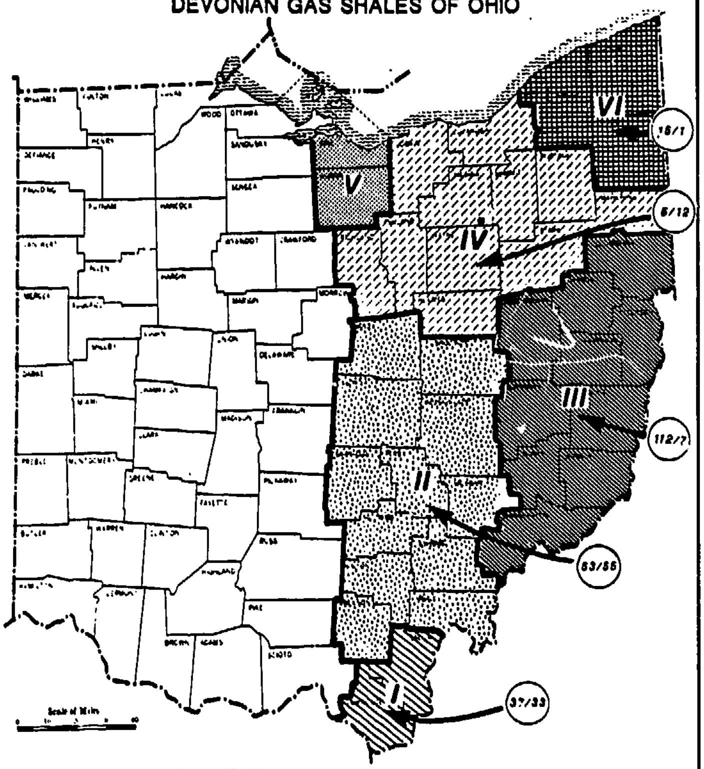


Figure 5
PRIMARY PARTITIONED AREAS
DEVONIAN GAS SHALES OF OHIO



#/ NUMBER OF OPEN-FLOW GAS PRODUCTION RECORDS
/# NUMBER OF LONG-TERM GAS PRODUCTION RECORDS

Figure 7
CUMULATIVE GAS RECOVERY
(160 Acres)

AREA II

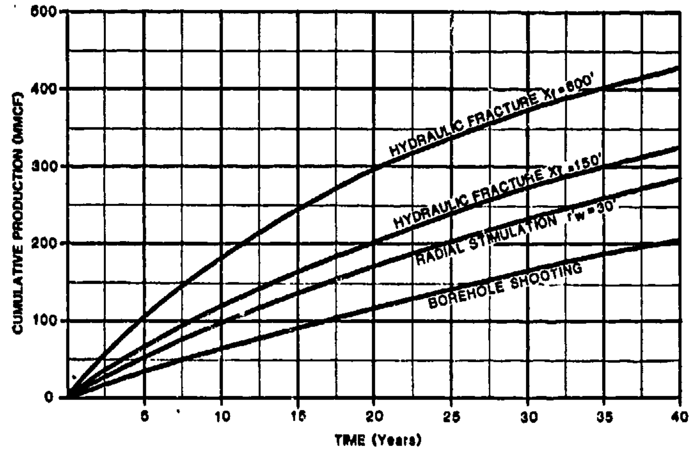


Figure 6
CUMULATIVE GAS RECOVERY
(160 Acres)

AREA I

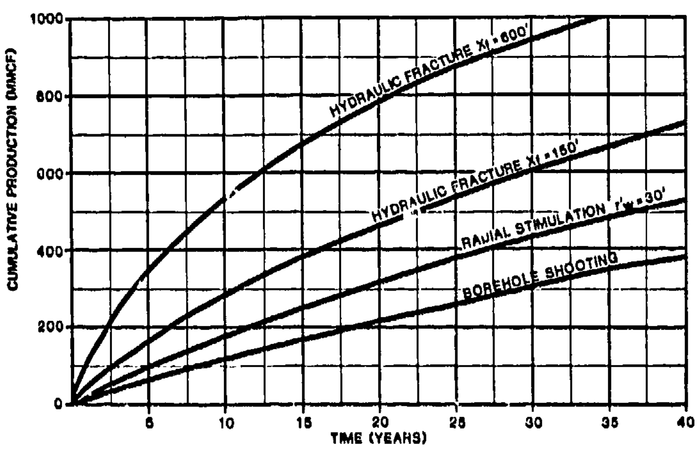


Figure 8
CUMULATIVE GAS RECOVERY
(80 Acres)

AREA I

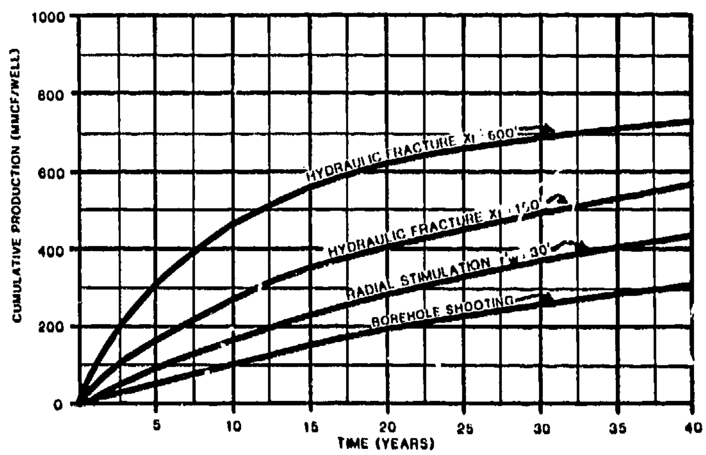
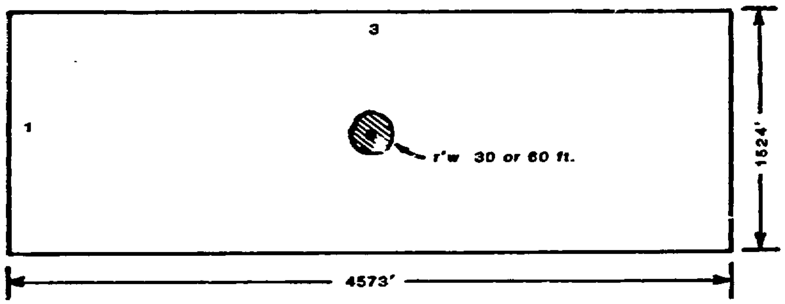


Figure 9

STIMULATION TREATMENT SCHEMATICS

RADIAL STIMULATION SCHEMATIC
(Not to Scale)
160 Acres



INDUCED FRACTURE SCHEMATIC
(Not to Scale)
160 Acres

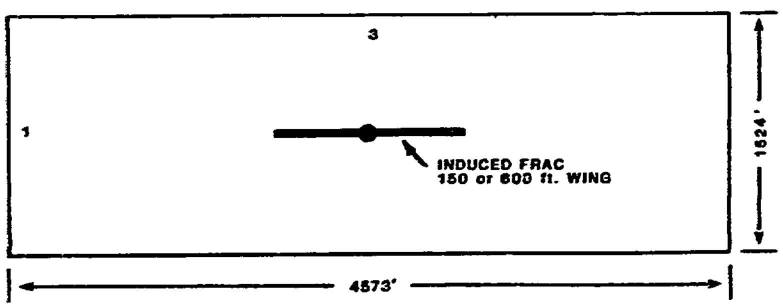
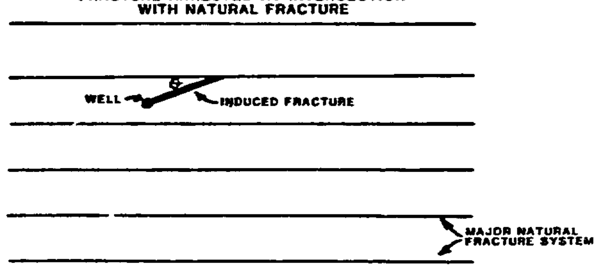


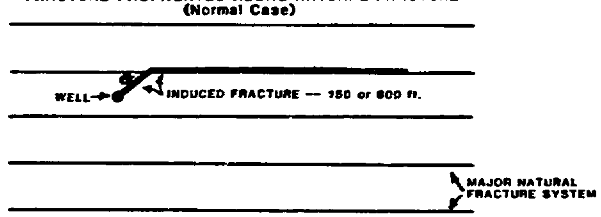
Figure 10

UNDERSTANDING OF INDUCED FRACTURE PROPAGATION

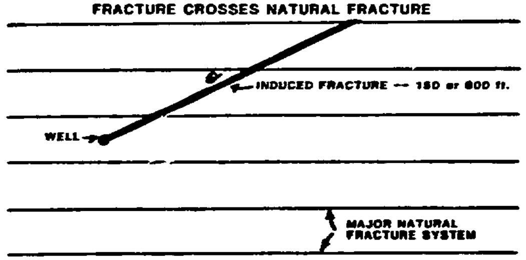
FRACTURE ARRESTED AT INTERSECTION WITH NATURAL FRACTURE



FRACTURE PROPAGATES ALONG NATURAL FRACTURE
(Normal Case)



FRACTURE CROSSES NATURAL FRACTURE



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